Available online at www.sciencedirect.com
ScienceDirect
Renewable and Sustainable Energy Reviews
12 (2008) 1465–1475
RENEWABLE & SUSTAINABLE ENERGY REVIEWS
www.elsevier.com/locate/rser

A review on risk-constrained hydropower scheduling in deregulated power market

Liu Hongling*, Jiang Chuanwen, Zhang Yan

Department of Electrical Engineering, Shanghai Jiaotong University, Huashan Road 1954, Shanghai 200030, PR China

Received 9 January 2007; accepted 23 January 2007

Abstract

In deregulated power market, hydro producer has in principle no other objective than to produce electricity and sell with maximum profit with lower market risk. Attention must focus on profit uncertainty caused by uncertainty in spot prices and reservoir inflow. The purpose of this review is to assess the state-of-the-art in hydropower operations considering profit risk under uncertainty and consider future directions for additional research and application. Physical and financial tools to hedge risk in bilateral market and risk-assessment methods are all discussed in detail. Furthermore, production resources can also be used to manage risk to a certain extent. This concept, when be integrated with variety of risk-management methods under stochastic optimal framework, has operational significance for hydro producer participating in electricity market.

Keywords: Hydro scheduling; Inflow risk; Price risk; Risk management; Stochastic optimization

Contents

*Corresponding author.
E-mail addresses: lbliuhl@hotmail.com, lb3799@sjtu.edu.cn (Liu Hongling), jiangcw@sjtu.edu.cn (Jiang Chuanwen).

1364-0321/$ - see front matter
doi:10.1016/j.rser.2007.01.018

1. Introduction

Traditionally, in a vertically integrated utility environment, the aim of reservoir management is to minimize expected costs, while maintaining an adequate security of supply. However, in deregulated power market, Gencos are usually entities owing generation resources and participating in the market with the sole objective of maximizing profits, without concern of the system, unless there is an incentive for it. For hydro producer, hydropower is different from other generation in the sense that it to some extent means storage of electricity. Large variability of water inflow means a large variability in profit [1]. For the inherent differences between electricity and any other commodity, short-term heightened volatility of electric-power prices provides the absolute need for performing risk management when trading energy. Thus, the decision makers have to consider the uncertainty in market prices and inflows, as well as technical constraints, while determining its power scheduling so as to meet the company's contractual obligations and its bidding strategy for electricity market.

This paper will cover the kinds of risks faced over different time frames by hydro producers. In restructured environment, hydro producers have to face price risk and inflow risk simultaneously. In long/mid-term scheduling frame, the output of hydro scheduling will provide power quantity basis for hydro producer participating in bilateral contract market. While in short-term scheduling frame, risk measurement is central to price risk. And based on the optimal scheduling, hydro producers should submit production bids to participate in day-ahead trading market.

For hydro producer, there are two mechanisms that can be based to manage market risk. The first one is to participate in bilateral market to hedge price risk. The total energy production is limited in a specified period. In an electricity portfolio, market risk can be mitigated by trade in bilateral market [2]. Presently, risk management which only considers day-ahead market mainly focus on thermal producer, aiming at price risk, mostly based on Markowitz's seminal work in the area of portfolio selection [3,4]. However, using variance of revenue as measure of risk in Markowitz's mean-variance model has been doubted: variance is symmetrical to the mean revenue, which means that the revenue above the mean will also be measured as risk. In fact, loss of revenue is the essential characteristic of risk. Meanwhile, risk-assessment methods can provide assistance for Gencos choosing more proper utility function to complete scheduling plan. It is known from portfolio optimization theory that risk management can be more effectively done using tools as

Nomenclature

I_t	inflow volume to the reservoir during period t
$I(i,t)$	unit status indicator with 1 means on and 0 means off
$N_{\min}$	minimum constraint on generation
$N_{\max}$	maximum constraint on generation
p_t	average spot price during period t
$q_{\min}$	minimum constraint on generation during period t
$q_{\max}$	maximum constraint on generation during period t
$q_{\min}(i)$	minimum generation limit of unit i
$q_{\max}(i)$	maximum generation limit of unit i
r_t	release volume from the reservoir during period t
$r_{\min}$	minimum constraint on release from the reservoir
$r_{\max}$	maximum constraint on release from the reservoir
s_t	storage volume of the reservoir at the end of period t
$s_{\min}$	minimum constraint on storage of the reservoir
$s_{\max}$	maximum constraint on storage of the reservoir
t	time index
T	time index for the end of scheduling period
$T^{\mathrm{on}}(i)$	minimum on time of unit i
$T^{\mathrm{off}}(i)$	minimum off time of unit i
$X_i^{\mathrm{on}}(t)$	time duration for which unit i has been on/off at time t
$X_i^{\mathrm{off}}(t)$	time duration for which unit i has been on/off at time t

Value-at-Risk (VaR) and Conditional Value-at-Risk (CVaR) [5]. VaR is a methodology developed by the financial industry to provide quantification for a company's portfolio's exposure to risk. It measures the expected maximum loss over a target horizon within a given confidence interval with clear physical meaning. VaR is considered as an open-loop solution, and very difficult for a Genco to modify its bidding strategy if it is not satisfied with the involved risk level. It has several limitations in practical applications. It does not provide a measure of the potential losses exceeding the VaR value. And it is difficult to optimize except when assuming normal distributions for underlying market variables [6]. CVaR has been proposed in recent years to overcome the limitation of VaR. CVaR is an integral, and it is inherently better behaved mathematically and more tractable in portfolio optimization [7]. It is convenient to measure price risk for optimal scheduling problem [8]. Moreover, it can be used in the optimization of a power portfolio by means of linear expressions for discrete random variables [9]. Financial derivatives, when well understood and properly utilized, are beneficial to the sharing and controlling of undesired risks through proper structured hedging strategies [10]. In [11], a risk management using futures contract, jointly with power scheduling, is considered in a mean-variance framework.

The second one is to change its operational decision. This can be integrated using financial instruments specifically designed to mange risk. This combined perspective is named integrated risk management [12]. In deregulated power market, hydro producer is exposed to both inflow and price uncertainty. This requires risk management should be under the stochastic-programming framework. To deal with uncertainty, implicit or

explicit methods have been widely used in reservoir optimal operations [13]. The penalty function can be used to describe the user's attitude seen as an inverse function [12]. Risk-assessment methods can also be integrated in hydro-optimal scheduling model to character the risk attitude of producer [8]. The new integrated mathematical model, which combines stochastic optimal methods with varieties of risk management methods, will provide more powerful basis for hydro producer to bid in electricity market.

The article is organized as follows. In the next section, hydropower-scheduling model in deregulated power market is formulated. Then the risk management in electricity is discussed. Then, risk-constrained optimal stochastic solution considering hydro-production resources as risk measurement is discussed. This is followed by conclusions.

2. Hydropower-scheduling model in deregulated power market

When electricity prices were regulated, hydropower optimization often considered only the inflow uncertainty. In deregulated market, price uncertainty must be considered in addition to inflow uncertainty. This makes the operation problem more challenging due to inclusion of the objective of minimizing risk. And Gencos comprehensively revise their generation-scheduling models. New models should include stochastic prices instead of using demand constraints and spinning reserve constraints. The hydropower-scheduling problem is decomposed into a planning hierarchy where the long/mid-term models provide boundary conditions for the short-term models. A single aggregate reservoir is assumed to keep the model simple and the producer in our case is a price taker.

2.1. Long-term scheduling model in deregulated power market

Majority of hydro-scheduling problem relate to the reservoir systems operations. Stochastic inflow, the release, which is related to the water passing through the turbine to make electricity and storage, describe reservoir's main characteristics. In long-term scheduling, the inflow must be dealt with as a stochastic variable. In deregulated electricity market, price uncertainty must be also included in the scheduling models. The main objective of optimization is to maximize the expected benefits and at the same time satisfy the system constraints.

A basic optimization long-term scheduling problem can be formulated as:

Objective Function

$$\text{Maximize } E_{\text{vp}}\left\{\sum_{t=1}^{T} q_t p_t\right\}, \tag{1}$$

where E_{vp} is the expectation over both inflow and price [22], q_t is the generation during period t and p_t is the average future spot price during period t.

Constraints

$$s_{t+1} = s_t + I_t - r_t,\ t = 1, \ldots, T, \tag{2}$$

$$r_{\min} \leqslant r_t \leqslant r_{\max},\ \forall t, \tag{3}$$

$$s_{\min} \leqslant s_t \leqslant s_{\max},\ \forall t, \tag{4}$$

$$q_{\min} \leqslant q(t) \leqslant q_{\max},\ \forall t. \tag{5}$$

2.2. Short-term scheduling model in deregulated power market

Mathematically, short-term hydro-scheduling problem is categorized as a class of large-scale, discrete, non-linear, and non-convex problem [14]. Therefore, it is crucial to have a more accurate model representing the hydraulic system for obtaining a reasonable schedule to guide the hydro-producer operations, e.g. minimum-up/minimum-down time limits are taken into account.

A basic optimization short-term scheduling problem can be formulated as:

Objective Function

$$\text{Maximize } E_{\text{vp}}\left\{\sum_{t=1}^{T} q_t p_t\right\}, \tag{6}$$

where q_t is the sum of production of operating units during period t.

Reservoir constraints

$$s_{t+1} = s_t + I_t - r_t,\ t = 1, \ldots, T, \tag{7}$$

$$r_{\min} \leqslant r_t \leqslant r_{\max},\ \forall t, \tag{8}$$

$$s_{\min} \leqslant s_t \leqslant s_{\max},\ \forall t. \tag{9}$$

System constraints

$$q_{\min}(t) \leqslant \sum_i q(i,t)I(i,t) \leqslant q_{\max}(t), \tag{10}$$

where the constraint can represent Genco's special requirements, e.g. a Genco may have minimum and maximum generation requirements in order to game in energy market.

Unit constraints

(a) Generation limits

$$I(i,t)q_{\min}(i) \leqslant q(i,t) \leqslant I(i,t)q_{\max}(i). \tag{11}$$

(b) Unit minimum starting up/down times

$$[X_i^{\text{on}}(t-1) - T^{\text{on}}(i)][(I(i,t-1) - I(i,t)] \geqslant 0, \tag{12}$$

$$[X_i^{\text{off}}(t-1) - T^{\text{off}}(i)][(I(i,t) - I(i,t-1)] \geqslant 0. \tag{13}$$

(c) Water consummation constraint

$$\sum_{t=1}^{T} r(i,t)\Delta t = W, \tag{14}$$

where W represents water consummation during single-time horizon Δt.

3. Risk management in electricity market

Risk management is the process of analyzing exposure to risk and determining how to best handle such exposure, including risk control and risk assessment. In [15], a good explanation of the concepts of robustness, exposure, hedge and regret are given. The importance to consider non-financial risk factors and their impact is also emphasized. A state-of-the-art summary of risk assessment in energy trading is provided in [6]. Techniques which were illustrated are VaR, CVaR and hedging using futures contracts.

3.1. Risk management in bilateral market

The fluctuation of spot price makes the risk management become an important content of market participants. Bilateral forward contracts, futures contracts and other financial instruments all can be used to hedge market risk in bilateral market.

3.1.1. Risk management with portfolio management

In electricity market, generation companies can mitigate trading risk with different physical trading (e.g. spot market and forward market). In a specified period, total physical energy is fixed, so allocating different portion to different physical trade leads to different portfolio management.

In classic portfolio theory, optimizing the expected return for a specified level of risk is a well-known problem. There are three dimensions to the problem—the expected return on each instrument in the portfolio, the risk in that return and the quantity of each instrument held [7]. The latter of these is the choice variable. Simplistically, portfolio optimization is the search for a vector of quantities that satisfies a number of constraints and provides minimum risk which is measured by total variance of maximum return or alternatively by the VaR. And risk/return metrics of such vectors comprise the "efficient frontier".

Both sides of forward contract have the specified revenues and expenses, for forward contract specifies the trade price of the future spot market regardless of the change of future spot price. Therefore, it is more suitable to risk-averse producer. And the purpose of signing forward contracts is to ensure stable power supply or sell, so it is acceptable for power producers owing generating and consuming abilities concurrently. However, forward trade lacks of liquidity for its widely adopted curb exchange. Traders will loose some gaining revenue opportunities while avoiding price risk.

Portfolio optimization as understood today is a static problem considering a portfolio at one point in time. There is need for theoretical and algorithmic development in dynamic, decision contingent optimization over a time horizon.

3.1.2. Risk management with financial instruments

Financial instruments, which are dependent on an underlying price, are defined as derivatives. They are beneficial to the sharing and controlling of undesired risks through proper structured hedging strategies when well understood and properly utilized [10].

The basic concepts and techniques for hedging of financial risks using the futures contracts are discussed in [16], where an analysis of actual data from power markets is performed. By trading in the futures market, Gencos decide to take a hedged position, which is not to profit from it but to protect itself from price risks. Direct hedging is one

such strategy wherein the futures contracts used are based on the spot market being evaluated. Under a direct hedging strategy, the idea is to find a significant covariance between the spot market and the corresponding futures market. If the link between the spot and futures market is weak, a direct hedging strategy may not always offer the lowest risk but cross hedging, which uses futures contracts from different markets, might offer a better risk reduction [16].

3.2. Risk assessment methods based on VaR and CVaR

A quantized risk index is needed to judge the feasibility of the risky optimal scheduling strategy for Gencos, especially after scheduling has been established. VaR and CVaR, as risk assessment methods, have been widely used in practical applications [17].

3.2.1. Value-at-risk

VaR is a risk-assessment tool that is used by financial institutions to measure the minimum occasional loss expected in a given portfolio within a stated time period [7]. VaR at the 100β percent confidence level is defined as the difference between the expected profit and the lower $100(1-\beta)$ percentile of the profit distribution [8]. Therefore, the probability that the monetary loss exceeds β-VaR is $(1-\beta)$. Risk-assessment model can be constructed with utility function and VaR method to optimize contract trade [18,19].

If the risk is modeled via the VaR, then the safety parameter that trades between profit and risk can be easily specified using standard normal tables. However, this requires the assumption that prices are Gaussian distributed. If it is to be relaxed, VaR would be very difficult to optimize. VaR also suffers from being intractable when computations are based on scenarios or historical observations [5]. A serious limitation of VaR, moreover, is that it provides no indication on the extent of the losses that might be suffered beyond the amount indicated by this measure. Moreover, VaR approach is an open-loop solution, and very difficult for a Genco to modify its bidding strategy if it is not satisfied with the involved risk level.

To overcome these limitations of VaR, CVaR has been proposed [5].

3.2.2. Conditional value-at-risk

CVaR is also known as the mean excess loss, mean shortfall, or tail VaR, which is defined as the conditional expectation of losses given that the loss exceeds a threshold value. For example, a 96% confidence CVaR value provides the mean of the expected losses for the potential loss values that exceed the 96% VaR value. By calculating the mean of the loss exceeding the VaR value, CVaR is known to be more consistent measure of risk than VaR, and provides a better indication of the potential losses exceeding the assumed confidence level [7]. The objective of Genco can be modeled as minimizing CVaR, pursuing the optimal scheduling under a given confidence level [20].

CVaR can be modeled by means of linear expressions for discrete random variables. This is an advantage of CVaR in the optimization of a power portfolio [20]. Moreover, since CVaR is greater than VaR, schedules with low CVaR necessarily have low VaR as well.

4. Risk management considering hydro-scheduling production resources

Currently, hydro-production scheduling and risk analysis is performed separately. This may result in considerably greater variation of income in different time periods than

preferred by the utilities. Continuing updating of the price and inflow forecast results in new production plans and thereby changes in the balance and the risk profile. Therefore, hydro scheduling considering risk management should be performed in stochastic programming framework.

4.1. Model of stochastic data

In deregulated power market, the inflow and the spot price all can be considered as stochastic variables. Stochastic price model is constructed based on future market price forecast, while stochastic inflow model is constructed based on statistic analysis of historical data.

A traditional approach to represent uncertainty is to estimate the parameters from historical data according to distributional assumptions, and then develop a stochastic model to take uncertainty into account [21]. Analysis of the price scenarios, which is based on EMPS-model, shows that the market price for each week strongly depends on the price of the foregoing week [22]. In order to use an optimization algorithm based on dynamic programming, AR model is preferred. The first-order discrete Markov price model is further expanded to incorporate long-term future position uncertainty of forward contract [23].

Scenario analysis method with a series of scenarios expressing stochastic data has been widely used in implicit or explicit stochastic optimal methods. A detailed literature review on scenario generation is given in [24]. To deal with multivariable uncertainties, the construction of a multivariate scenario tree is suggested. Scenario tree captures the dynamics of decision making as the decisions are adjusted to the currently available information. Clustering method [25], non-linear optimal method [26] and heuristic method [27] have been employed to generate scenario tree given the statistical properties of the stochastic variables. To deal with uncertainty, multiple-scenario method is proposed to simplify the representation of the stochastic inflow process [28]. The inflow process is approximated by a few discrete values for each stage. With a few stages, the number of possible scenarios is limited, and can be dealt with in an optimization procedure. This processing mode has typical significance in dealing with stochastic data, and can be applied in stochastic dynamic programming (SDP) and stochastic dual dynamic programming (SDDP) optimization methods. Monte-Carlo simulation method can also be applied to generate scenarios, and scenario reduction techniques must be applied to reduce the number of scenarios [29].

4.2. Risk-constrained optimal stochastic solution

The most general way of solving the stochastic scheduling problem is to use SDP to find the optimal operation policy. With more than one or two reservoirs, however, one runs into the well-known dimensional problems of dynamic programming [30]. In [31], SDDP is first proposed, which uses a decomposition method according to time stages, similar to that of dynamic programming. At each stage, a small LP problem has to be solved. An application of SDDP to seasonal planning is showed in a part of the Norwegian hydro-dominated power system [29].

On the research of multi-stage, multi-dimension stochastic optimization problem, Bender's decomposition overcomes the shortcoming of the "curse of dimensionality" in

dynamic programming. By decomposing the problem into multi-stage, it makes the complicated problem easy to track and so can solve very large-scale linear optimization problems. BD has been proved an efficient methodology to solve the hydro-energy operation problem [32,33]. However, it still belongs to implicit methods and the accuracy of the solution depends on the scenarios. Also, the problem must be approximated using piecewise linear convex functions which is suitable for linear objective functions. Lagrangian relaxation idea, as another decomposition method, is very popular in power optimization. Combined with certain global optimization technique (e.g. heuristics [34,35]), stochastic Lagrangian relaxation method is also proved efficient [36].

Production planning and risk management can be integrated in order to maximize expected profit at some acceptable level of risk. In the integrated model, the price and inflow scenarios are input to the hydro scheduling. To minimize the risk of the total electricity portfolio, generation resources and committed forward contracts can be included in the same model. The expected shortfall, which is defined as profit underperformance relative to some preset profit targets at various periods, represents the risk of the stochastic profit [37]. The penalty function can be seen as an inverse function when used to describe the user's attitude. The risk level can be controlled by setting revenue targets, and progressive penalty functions for income below user-specified limits are contained in the objective function. The solution method, which is similar to combination of SDDP and SDP, is used [12]. The above approach is to penalize each scenario in which the company's profit is lower than a certain objective value. Penalizing the expected downside risk in the objective function will lead to minimum downside risk at the cost of reducing profit. This has the advantage of not requiring a constraint that couples the different scenarios. A disadvantage of this method is that it does not impose an explicit limit for the losses that the company may face. If constraint on the expected downside risk can be dynamically changed, a tradeoff between the expected payoff and undertaking risk will be obtained. Conditional VaR is another approach, which has better risk and mathematical properties as risk measure. It establishes a hard limit on the expected value of losses for the subset of scenarios in which the shortfall exceeds the VaR at a given confidence level. CVaR method, which has the characteristic of being modeled by means of linear expressions for discrete random variables, provides convenience to its application in scheduling problem [8].

All these methods have great value for hydro producers to control market risk. And combining hydro-production scheduling and risk analysis under the stochastic optimal framework develops powerful tools for hydro producers to participate in electricity market with their actual risk attitude.

5. Conclusion

In deregulated electricity market, a major concern for hydro producers is the profit uncertainty caused by e.g. uncertainty in spot prices and reservoir inflow. This requires hydro scheduling considering price risk and inflow risk under the stochastic framework. As mentioned above, there are two mechanisms that a hydro producer can use in order to manage market risk. The first one is to participate in bilateral market to hedge price risk. This includes allocating its limited physical energy in an electric portfolio and hedge risk with financial derivatives. The second one is to change its operational decisions, which implies that the probabilities function of operating profit should be constructed at the same

time as the hedging strategy is decided. A variety of risk-management methods are reviewed in deregulated power market, such as penalty method, risk-constraint method and risk measure method (e.g. VaR, CVaR). These methods should be realized in stochastic programming framework for the uncertainties of prices and inflow. Kinds of implicit or explicit stochastic programming methods have been used in hydro-scheduling problem successfully, to overcome the key difficulty in optimization under uncertainty, hybrid methods can accommodate more complicated constraints and have great application prospect.

Acknowledgments

The authors gratefully acknowledge the support of Yalong River joint research foundation of National Natural Science Foundation of China (NSFC) and Ertan Hydropower Development Company Ltd. (no: 50539140).

References

[1] Shrestha GB, Pokharek BK, Lie TT, Fleten S-E. Medium term power planning with bilateral contracts. IEEE Trans Power Syst 2005;20(2):627–33.
[2] Liu M, Wu FF, Ni Y. Market allocation between bilateral contracts and spot market without financial transmission rights. IEEE Power Eng Soc Gen Meet 2003:1007–11.
[3] Conejo AJ, Nogales FJ, Arroyo JM, García-Bertrand R. Risk-constrained self-scheduling of a thermal power producer. IEEE Trans Power Syst 2004;19(3):1569–74.
[4] Yamin HY, Shahidepour SM. Risk and profit in self-scheduling for Gencos. IEEE Trans Power Syst 2004; 19(4):2104–6.
[5] Rockafellar RT, Uryasev S. Optimization of conditional value-at-risk. J Risk 2000;2:1–26.
[6] Dahlgren R, Liu CC, Lawarrée J. Risk assessment in energy trading. IEEE Trans Power Syst 2003; 18(2):503–11.
[7] Denton M, Palmer A, Agtash SA, Skantze P. Managing market risk in energy. IEEE Trans Power Syst 2005;18(2):494–502.
[8] Jabr RA. Robust self-scheduling under price uncertainty using conditional value-at-risk. IEEE Trans Power Syst 2005;20(4):1852–8.
[9] Cabero J, Baíllo Á, Cerisola S, Ventosa M, García-Alcalde A, Perán F, et al. A medium-term integrated risk management model for hydrothermal generation company. IEEE Trans Power Syst 2005;20(3):1379–88.
[10] Deng SJ, Oren SS. Electricity derivatives and risk management. Energy 2006;31(6):940–53.
[11] BjØrgan R, Liu CC, Lawarrée J. Financial risk management in a competitive electricity market. IEEE Trans Power Syst 1999;21(6):1285–91.
[12] Mo B, Gjelsvik A, Grundt A. Integrated risk management of hydro power scheduling and contract management. IEEE Trans Power Syst 2001;16(2):216–21.
[13] Labadie JW. Optimal operation of multireservoir systems state-of-the-art review. J Water Resour Plan Manage 2004;130(2):93–111.
[14] Chang GW, Aganagic M, Waight JG, Medina J, Burton T, Reeves S, et al. Experiences with mixed integer linear programming based approaches on short-term hydro scheduling. IEEE Trans Power Syst 2001;16(4): 743–9.
[15] Pereira M, McCoy M, Merrill H. Managing risk in the new power business. IEEE Comput Appl Power 2000;13(2):18–27.
[16] Tanlapco E, Lawarree J, Liu CC. Hedging with futures contracts in a deregulated industry. IEEE Trans Power Syst 2002;17(3):577–82.
[17] Available online at 〈http://www.gloriamundi.org〉.
[18] Zhou M, Nie Y, Li G, Ni Y. Long-term electricity purchasing scheme and risk assessment in power market. Proc CSEE 2006;26(6):116–22 [in Chinese].
[19] Zhang X, Wang X. Generator's optimal electricity volume based on block electricity contracts. Proc CSEE 2006;26(8):12–7 (in Chinese).

[20] Wang R, Jincheng S, Yang F, et al. Combined bidding strategy and model for power suppliers based on CVaR risk measurement techniques. Automat Electric Power Syst 2005;29(14):5–9.
[21] Escudero LF, de la Fuente JL, Garcia C, Prieto FJ. Hydropower generation management under uncertainty via scenario analysis and parallel computation. IEEE Trans Power Syst 1996;11(2):683–9.
[22] Fosso OB, Gjelsvik A, Haugstad A, Mo B, Wangensteen I. Generation scheduling in a deregulated system. The Norwegian case. IEEE Trans Power Syst 1999;14(1):75–81.
[23] Mo B, Gjelsvik A, Grundt A, Kåresen K. Optimisation of hydropower operation in a liberalized market with focus on price modeling. IEEE Porto Power Tech Proc 2001.
[24] Dupačová J, Consigli G, Wallce SW. Scenarios for multistage stochastic programs. Ann Oper Res 2000;100: 25–53.
[25] Pflug GC. Scenario tree generation for multiperiod financial optimization by optimal discretization. Math Prog 2001;89(2):251–71.
[26] HØyland K, Wakkace SW. Generating scenario trees for multistage decision problems. Manage Sci 2001; 47(2):295–307.
[27] HØyland K, Kaut M, Wakkace SW. A heuristic for moment-matching scenario generation. Comput Optim Appl 2003;24:169–85.
[28] Rotting TA, Gjelsvik A. Stochastic dual dynamic programming for seasonal scheduling in the Norwegian power system. IEEE Trans Power Syst 1992;7(1):273–9.
[29] Kuska NG, Heitsch H, Römisch W. Scenario reduction and scenario tree construction for power management problems. IEEE Bologna Power Tech Proc 2003;3:23–6.
[30] Pereira MV, Campodonico NM, Kelman R. Application of stochastic dual DP and extensions to hydrothermal scheduling. Online report ⟨http://www.psr-inc.com.br.reports.asp⟩, PSRI Technical Report 012/99.
[31] Pereira MVF. Optimal stochastic operations scheduling of large hydroelectric systems. Int J Electrical Power Energy Syst 1989;11(3):161–9.
[32] Gorenstin BG, Campodonico NM, Costa JP, Pereira MV. Stochastic optimization of a hydro-thermal system including network constraints. IEEE Trans Power Syst 1992;7(2):791–7.
[33] Gorenstin BG, Campodonico NM, Costa JP, Pereira MV. Power system expansion planning under uncertainty. IEEE Trans Power Syst 1993;8(1):129–36.
[34] Jiang C, Bompard E. A self-adaptive chaotic particle swam algorithm for short term hydroelectric system scheduling in deregulated environment. Energy Convers Manage 2005;46(17):2689–96.
[35] Reis LFR, Walters GA, Savic D, Chaudhry FH. Multi-reservoir operation planning using hybrid genetic algorithm and linear programming (GA-LP): an alternative stochastic approach. Water Resour Manage 2005;19(6):831–48.
[36] Nowak MP, Römisch W. Stochastic Lagrangian relaxation applied to power scheduling in a hydro-thermal system under uncertainty. Ann Oper Res 2000;100:251–72.
[37] BjØkvoll T, Fleten SE, Nowak MP. Power generation planning and risk management in a liberalized market. IEEE Porto Power Tech Proc 2001.